PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
May 05, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) **May 5, 2010**

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**1-14569**	**76-0582150**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

Registrant s telephone number, including area code **713-646-4100**

(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press Release dated May 5, 2010.

Item 2.02 and Item 7.01. Results of Operations and Financial Condition; Regulation FD Disclosure

Plains All American Pipeline, L.P. (the Partnership) today issued a press release reporting its first-quarter 2010 results. We are furnishing the press release, attached as Exhibit 99.1, pursuant to Item 2.02 and Item 7.01 of Form 8-K. Pursuant to Item 7.01 we are providing detailed guidance for financial performance for the second quarter and second half of calendar 2010. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under this Item 7.01 shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Disclosure of Second Quarter and Second Half 2010 Guidance

EBIT and EBITDA (each as defined below in Note 1 to the Operating and Financial Guidance table) are non-GAAP financial measures. Net income and cash flows from operating activities are the most directly comparable GAAP measures to EBIT and EBITDA. In Note 9 below, we reconcile net income to EBIT and EBITDA for the 2010 guidance periods presented. It is, however, impractical to reconcile EBIT and EBITDA to cash flows from operating activities for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled Non-GAAP Reconciliation), which presents a historical reconciliation of certain commonly used non-GAAP financial measures, including EBIT and EBITDA. We present EBIT and EBITDA because we believe they provide additional information with respect to both the performance of our fundamental business activities and our ability to meet our future debt service, capital expenditures and working capital requirements. We also believe that debt holders commonly use EBITDA to analyze partnership performance. In addition, we have highlighted the impact of our equity compensation plans, gains and losses from other derivative activities, and PNGS contingent consideration fair value adjustment on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

We based our guidance for the three-month period ending June 30, 2010 and the six-month and twelve-month periods ending December 31, 2010 on assumptions and estimates that we believe are reasonable given our assessment of historical trends (modified for changes in market conditions), business cycles and other reasonably available information. Projections covering multi-quarter periods contemplate inter-period changes in future performance resulting from new expansion projects, seasonal operational changes (such as LPG sales) and acquisition synergies. Our assumptions and future performance, however, are both subject to a wide range of business risks and uncertainties, so no assurance can be provided that actual performance will fall within the guidance ranges. Please refer to information under the caption Forward-Looking Statements and Associated Risks below. These risks and uncertainties, as well as other unforeseeable risks and uncertainties, could cause our actual results to differ materially from those in the following table. The operating and financial guidance provided below is given as of the date hereof, based on information known to us as of May 4, 2010. We undertake no obligation to publicly update or revise any forward-looking statements.

Plains All American Pipeline, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	Actual 3 Months Ended 3/31/2010	**Guidance (1) 3 Months Ending June 30, 2010 Low**	**High**	**6 Months Ending December 31, 2010 Low**	**High**	**12 Months Ending December 31, 2010 Low**	**High**
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 503	$ 461	$ 478	$ 973	$ 988	$ 1,937	$ 1,969
Field operating costs	(162)	(189)	(184)	(356)	(351)	(707)	(697)
General and administrative expenses	(62)	(56)	(54)	(106)	(101)	(224)	(217)
	279	216	240	511	536	1,006	1,055
Depreciation and amortization expense	(67)	(68)	(65)	(132)	(127)	(267)	(259)
Interest expense, net	(58)	(61)	(59)	(126)	(122)	(245)	(239)
Income tax expense		(2)	(1)	(2)	(1)	(4)	(2)
Other income (expense), net	(3)	(1)		(1)	(1)	(5)	(4)
Net Income	**$ 151**	**$ 84**	**$ 115**	**$ 250**	**$ 285**	**$ 485**	**$ 551**
Less: Net income attributable to the noncontrolling interest		(3)	(2)	(7)	(6)	(10)	(8)
Net Income attributable to Plains	**$ 151**	**$ 81**	**$ 113**	**$ 243**	**$ 279**	**$ 475**	**$ 543**
Net Income to Limited Partners	$ 112	$ 41	$ 72	$ 157	$ 192	$ 310	$ 376
Basic Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	136	136	136	136	136	136	136
Net Income Per Unit	$ 0.80	$ 0.28	$ 0.51	$ 1.13	$ 1.39	$ 2.21	$ 2.70
Diluted Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	137	137	137	137	137	137	137
Net Income Per Unit	$ 0.80	$ 0.28	$ 0.51	$ 1.12	$ 1.38	$ 2.20	$ 2.68
EBIT	**$ 209**	**$ 147**	**$ 175**	**$ 378**	**$ 408**	**$ 734**	**$ 792**
EBITDA	**$ 276**	**$ 215**	**$ 240**	**$ 510**	**$ 535**	**$ 1,001**	**$ 1,051**
Selected Items Impacting Comparability							
Equity compensation charge	$ (14)	$ (10)	$ (10)	$ (15)	$ (15)	$ (39)	$ (39)
Gains / (Losses) from other derivative activities	19					19	19
PNGS contingent consideration fair value adjustment	(1)					(1)	(1)
	$ 4	$ (10)	$ (10)	$ (15)	$ (15)	$ (21)	$ (21)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 134	$ 123	$ 128	$ 275	$ 280	$ 532	$ 542
Facilities	61	64	67	139	142	264	270
Supply and Logistics	79	38	55	112	129	229	263
Other Income (Expense), net	(2)			(1)	(1)	(3)	(3)
Adjusted EBITDA	$ 272	$ 225	$ 250	$ 525	$ 550	$ 1,022	$ 1,072
Adjusted Net Income attributable to Plains	$ 147	$ 91	$ 123	$ 258	$ 294	$ 496	$ 564
Adjusted Basic Net Income per Limited Partner Unit	$ 0.78	$ 0.36	$ 0.59	$ 1.24	$ 1.50	$ 2.38	$ 2.87

Adjusted Diluted Net Income per Limited Partner Unit	$	0.77	$	0.36	$	0.59	$	1.23	$	1.49	$	2.36	$	2.85

(1) The projected average foreign exchange rate is $1.02 and $1.05 Canadian dollar to $1 U.S. Dollar, respectively for the three months ending June 30, 2010 and six months ending December 31, 2010. The rate as of May 4, 2010 was $1.025 Canadian dollar to $1 U.S. Dollar. A $0.10 change in the FX rate will impact EBITDA for the last nine months of 2010 by approximately $9 million.

Notes and Significant Assumptions:

1. *Definitions.*

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Segment Profit	Net revenues (including equity earnings, as applicable) less field operating costs and segment general and administrative expenses
Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other natural gas-related petroleum products (primarily propane and butane)
FX	Foreign currency exchange
General partner (GP)	As the context requires, general partner refers to any or all of (i) PAA GP LLC, the owner of our 2% general partner interest, (ii) Plains AAP, L.P., the sole member of PAA GP LLC and owner of our incentive distribution rights and (iii) Plains All American GP LLC, the general partner of Plains AAP, L.P.
Class B units	Class B units of Plains AAP, L.P.
PNGS	PAA Natural Gas Storage, LLC

2. *Operating Segments*. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. The following is a brief explanation of the operating activities for each segment as well as key metrics.

a. *Transportation.* Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in the Butte and Frontier pipeline systems and Settoon Towing, in which we own noncontrolling interests.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of internal growth projects. Actual volumes are influenced by maintenance schedules at refineries, production declines, weather and other natural disasters including hurricanes, changes in the quantity of inventory held in tanks, and other external factors beyond our control. We forecast adjusted segment profit using the volume assumptions in the table below, priced at forecasted tariff rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation. Actual segment profit could vary materially depending on the level and mix of volumes transported or expenses incurred during the period.

The following table summarizes our total pipeline volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

	Actual		2010 Guidance	
	Three Months	**Three Months**	**Six Months**	**Twelve Months**

	Ended March 31,	Ending June 30,	Ending December 31,	Ending December 31,

($ in thousands)
Financial Assets (Liabilities):

Derivative liabilities
$
—

$
(13,101
)

$
—

$
(13,101
)
Total
$
—

$
(13,101
)

$
—

$
(13,101
)

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CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2013:

	Quoted Prices in Active Markets (Level 1) ($ in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative liabilities	$—	$(8,071)	$—	$(8,071)
Total	$—	$(8,071)	$—	$(8,071)

Fair Value of Other Financial Instruments. The estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. The carrying values of financial instruments comprising cash and cash equivalents approximate fair values due to the short-term maturities of these instruments.

4. Income Taxes

The Trust is a Delaware statutory trust that is treated as a partnership for U.S. federal income tax purposes. The Trust is not required to pay federal or state income taxes. Accordingly, no provision for federal or state income tax has been made.

Trust unitholders are treated as partners of the Trust for U.S. federal income tax purposes. The Trust Agreement contains tax provisions that generally allocate the Trust's income, deductions and credits among the Trust unitholders in accordance with their percentage interests in the Trust. The Trust Agreement also sets forth the tax accounting principles to be applied by the Trust.

5. Related Party Transactions

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $175,000 to the Trustee, paid in equal quarterly installments. The administrative fee may be adjusted for inflation by no more than 3% in any calendar year beginning in 2015.

Agreements with Chesapeake. In connection with the initial public offering and the conveyance of the Royalty Interests to the Trust, the Trust entered into an administrative services agreement, a development agreement and a registration rights agreement with Chesapeake.

Pursuant to the administrative services agreement, Chesapeake provides the Trust with certain accounting, tax preparation, bookkeeping and information services related to the Royalty Interests and the registration rights agreement. In return for the services provided by Chesapeake under the administrative services agreement, the Trust pays Chesapeake, in equal quarterly installments, an annual fee of $200,000, which will remain fixed for the life of the Trust. Chesapeake is also entitled to receive reimbursement for its actual out-of-pocket fees, costs and expenses incurred in connection with the provision of any of the services under the agreement.

Additionally, the administrative services agreement established Chesapeake as the Trust's hedge manager, pursuant to which Chesapeake has the authority, on behalf of the Trust, to administer the Trust's derivative contracts. As hedge manager, Chesapeake also has authority to terminate, restructure or otherwise modify all or any portion of the derivative contracts to the extent that Chesapeake reasonably determines, acting in good faith, that the volumes hedged under such contracts exceed, or are expected to exceed, the combined estimated production attributable to the Royalty Interests over the periods hedged. However, in fulfilling its role as hedge manager, Chesapeake does not act as a fiduciary for the Trust and has no affirmative duty to modify any of the Trust's derivative contracts, except as required by the derivative contracts and the administrative services agreement. Moreover, the Trust has agreed to indemnify Chesapeake for any actions it takes in this regard.

The administrative services agreement will terminate upon the earliest to occur of (a) the date the Trust shall have dissolved and wound up its business and affairs in accordance with the Trust Agreement, (b) the date that all of the

Royalty Interests have been terminated or are no longer held by the Trust, (c) with respect to services to be provided

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CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

with respect to any Underlying Properties being transferred by Chesapeake, the date that either Chesapeake or the Trustee may designate by delivering 90-days prior written notice, provided that Chesapeake's drilling obligation has been completed and the transferee of such Underlying Properties assumes responsibility to perform the services in place of Chesapeake or (d) a date mutually agreed by Chesapeake and the Trustee.

The development agreement obligates Chesapeake to drill, cause to be drilled or participate as a non-operator in the drilling of the Development Wells on or prior to June 30, 2016. Additionally, based on Chesapeake's assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake has also agreed not to drill and complete, or permit any other person within its control to drill and complete, any well in the AMI other than the Development Wells until Chesapeake has met its obligation to drill the Development Wells.

In drilling the Development Wells, Chesapeake is required to act diligently and as a reasonably prudent oil and gas operator would act under the same or similar circumstances as if it were acting with respect to its own properties, disregarding the existence of the Royalty Interests as burdens affecting such properties (the "Reasonably Prudent Operator Standard"). Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the Development Wells will be generally consistent with those used for the Producing Wells, the existing Development Wells and other Colony Granite Wash producing wells outside of the AMI.

Under the development agreement, Chesapeake is credited for drilling one full Development Well if the perforated length of the well is equal to or greater than 3,500 feet and Chesapeake's net revenue interest in the well is equal to 52.0%. For wells with a perforated length that is less than 3,500 feet, and for wells in which Chesapeake has a net revenue interest greater than or less than 52.0%, Chesapeake receives proportionate credit.

A wholly owned subsidiary of Chesapeake has granted to the Trust the Drilling Support Lien covering Chesapeake's retained interest in the AMI (except its interest in the Producing Wells, Development Wells and any other wells not subject to the Royalty Interests) in order to secure the estimated amount of the drilling costs for the Trust's interests in the Development Wells. The maximum amount that may be obtained by the Trust pursuant to the Drilling Support Lien initially could not exceed $262.7 million. As Chesapeake fulfills its drilling obligation over time, the total amount that may be recovered is proportionately reduced and completed Development Wells are released from the lien. If Chesapeake does not fulfill its drilling obligation by June 30, 2016, the Trust may foreclose on any remaining interest in the AMI that is subject to the Drilling Support Lien. Any amounts actually recovered in a foreclosure action would be applied to the completion of Chesapeake's drilling obligation and would not result in any distribution to the Trust unitholders.

Chesapeake's drilling activity with respect to the Development Wells is consistent with its intent to meet the drilling obligation contemplated by the development agreement. See Risks and Uncertainties in Note 2 regarding the operated rig count reduction in August 2013 from four rigs to two rigs.

The Trust also entered into a registration rights agreement for the benefit of Chesapeake and certain of its affiliates (each, a "holder"). Pursuant to the registration rights agreement, the Trust agreed to register the Trust units held by each such holder for resale under the Securities Act of 1933, as amended. In connection with the preparation and filing of any registration statement, Chesapeake will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust, and any underwriting discounts and commissions, which will be borne by the seller of the Trust units.

Loan Commitment. Pursuant to the Trust Agreement, if at any time the Trust's cash on hand (including available cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will loan funds to the Trust necessary to pay such expenses. Any funds loaned by Chesapeake pursuant to this commitment will be limited to the payment of current accounts payable or other obligations to trade creditors in connection with obtaining goods or services or the payment of other current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans funds pursuant to this commitment, unless Chesapeake agrees otherwise, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid. There were no loans outstanding as of June 30, 2014 or December 31, 2013.

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

6. Distributions to Unitholders

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's expenses, approximately 60 days following the completion of each quarter through (and including) the quarter ending June 30, 2031.

For the six months ended June 30, 2014 and 2013, the Trust declared and paid the following cash distributions:

Calendar Quarter	Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
Q2 2014	December 2013 - February 2014	May 30, 2014	$0.6454	$—
Q1 2014	September 2013 - November 2013	March 3, 2014	$0.6624	$—
Q2 2013	December 2012 - February 2013	May 31, 2013	$0.6900	$0.3010
Q1 2013	September 2012 - November 2012	March 1, 2013	$0.6700	$0.3772

7. Subsequent Events

On August 7, 2014, the Trust declared a cash distribution of $0.5796 per common unit, consisting of proceeds attributable to production from March 1, 2014 to May 31, 2014. The distribution will be paid on August 29, 2014 to record unitholders as of August 19, 2014. The Trust's quarterly income available for distribution was $0.4347 per unit, which was $0.2453 below the applicable subordination threshold of $0.6800. All of the quarterly income available for distribution will be used to make the common unit distribution and no subordinated unit distribution will be paid.

Distributable income attributable to production from March 1, 2014 to May 31, 2014 was calculated as follows (in thousands except for unit and per unit amounts):

REVENUES:	
Royalty income[(a)]	$23,606
EXPENSES:	
Production taxes	494
Trust administrative expenses[(b)]	408
Derivative settlement loss	2,383
Total Expenses	3,285
Distributable income available to unitholders	$20,321
Distributable income per common unit (35,062,500 units)	$0.5796
Distributable income per subordinated unit (11,687,500 units)[(c)]	$—

(a) Net of certain post-production expenses.

(b) Includes cash reserves withheld.

(c) As the common unit distribution is below the applicable subordination threshold, no distribution was declared for the subordinated units.

ITEM 2. Trustee's Discussion and Analysis of Financial Condition and Results of Operations

Introduction

The following discussion and analysis is intended to help the reader understand the Trust's financial condition and results of operations. This discussion and analysis should be read in conjunction with the Trust's unaudited interim financial statements and the accompanying notes relating to the Trust and the Underlying Properties included in Item 1 of Part I of this Quarterly Report as well as the Trust's Annual Report on Form 10-K for the year ended December 31, 2013 (the "2013 Form 10-K"). Capitalized items in this Item 2 have the same meanings ascribed to them in Note 1 to the Trust's financial statements included in Item 1 of Part I of this Quarterly Report.

Overview

The Trust is a statutory trust formed in June 2011 under the Delaware Statutory Trust Act. The business and affairs of the Trust are managed by the Trustee and, as necessary, the Delaware Trustee. The Trust does not conduct any operations or activities other than owning the Royalty Interests and activities related to such ownership. The Trust's purpose is generally to own the Royalty Interests, to distribute to the Trust unitholders cash that the Trust receives in respect of the Royalty Interests and the derivative contracts (described in Note 3 to the financial statements contained in Item 1 of Part I of this Quarterly Report) and to perform certain administrative functions in respect of the Royalty Interests and the Trust units. The Trust derives all or substantially all of its income and cash flow from the Royalty Interests and the derivative contracts. The Trust is treated as a partnership for federal income tax purposes.

Concurrent with the Trust's initial public offering in November 2011, Chesapeake conveyed the Royalty Interests to the Trust effective July 1, 2011, which included interests in (a) 69 Producing Wells in the Colony Granite Wash play and (b) 118 Development Wells that have since been or that are to be drilled in the Colony Granite Wash play on properties within the AMI. Chesapeake is obligated to drill, cause to be drilled or participate as a non-operator in the drilling of the Development Wells from drill sites in the AMI on or prior to June 30, 2016. Additionally, based on Chesapeake's assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. As of June 30, 2014, Chesapeake had drilled and completed 84 wells within the AMI (approximately 93.4 Development Wells as calculated under the development agreement) and had drilled two additional wells within the AMI that were awaiting completion as of August 4, 2014.

The Trust is not responsible for any costs related to the drilling of the Development Wells or any other operating or capital costs of the Underlying Properties, and Chesapeake is not permitted to drill and complete any well in the Colony Granite Wash formation on acreage included within the AMI for its own account until it has satisfied its drilling obligation to the Trust.

The Royalty Interests entitle the Trust to receive 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sales of production of oil, NGL and natural gas attributable to Chesapeake's net revenue interest in the Producing Wells and 50% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sales of oil, NGL and natural gas production attributable to Chesapeake's net revenue interest in the Development Wells. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, NGL and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by Chesapeake or its affiliates.

On November 16, 2011, Chesapeake novated to the Trust, and the Trust became party to, derivative contracts covering a portion of the production attributable to the Royalty Interests from October 1, 2011 through September 30, 2015. The Trust's distributable income includes net settlements under these derivative contracts. The fair value of the derivative contracts as of June 30, 2014 and December 31, 2013 was a net liability of $13.1 million and $8.1 million, respectively.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031.The distribution made in the first quarter of 2014, consisting of proceeds attributable to production from September 1, 2013 through November 30, 2013, was made on March 3, 2014 to record unitholders as of February 19, 2014. The distribution made in the second quarter of 2014, consisting of

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proceeds attributable to production from December 1, 2013 through February 28, 2014, was made on May 30, 2014 to record unitholders as of May 20, 2014.

The amount of Trust revenues and cash distributions to Trust unitholders fluctuates from quarter to quarter depending on several factors, including:

- timing and amount of initial production and sales from the Development Wells;
- oil, NGL and natural gas prices received;
- volumes of oil, NGL and natural gas produced and sold;
- amounts received from, or paid under, derivative contracts;
- certain post-production expenses and any applicable taxes; and
- the Trust’s expenses.

Subordination Threshold. In order to provide support for cash distributions on the common units, Chesapeake agreed to subordinate 11,687,500 of the Trust units retained following the initial public offering of common units, which constitute 25% of the outstanding Trust units. The subordinated units are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to pay a cash distribution on the common units that is no less than 80% of the target distribution for the corresponding quarter. If there is not sufficient cash to fund such a distribution on all of the common units, the distribution to be made with respect to the subordinated units is reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on all the common units, including the common units held by Chesapeake.

Incentive Threshold. In exchange for agreeing to subordinate a portion of its Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter is 20% greater than the target distribution for such quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold is paid to the Trust unitholders, including Chesapeake, on a pro rata basis.

At the end of the fourth full calendar quarter following Chesapeake’s satisfaction of its drilling obligation with respect to the Development Wells, the subordinated units will automatically convert into common units on a one-for-one basis and Chesapeake’s right to receive incentive distributions will terminate. With respect to distributions for quarters following the fourth full quarter after Chesapeake's satisfaction of its Development Well drilling obligation, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share on a pro rata basis in the Trust’s distributions. The period during which the subordinated units are outstanding is referred to as the subordination period.

The following table sets forth the subordination threshold and the incentive threshold for each calendar quarter through the second quarter of 2017, as established in the Trust Agreement:

Period	Subordination Threshold[(a)] (per unit)	Incentive Threshold[(a)]
2014:		
First Quarter[(b)]	$0.69	$1.04
Second Quarter[(c)]	$0.68	$1.02
Third Quarter	$0.69	$1.03
Fourth Quarter	$0.66	$0.99
2015:		
First Quarter	$0.66	$0.99
Second Quarter	$0.68	$1.02
Third Quarter	$0.64	$0.96
Fourth Quarter	$0.56	$0.84
2016:		
First Quarter	$0.51	$0.76
Second Quarter	$0.47	$0.70
Third Quarter	$0.44	$0.66
Fourth Quarter	$0.41	$0.62
2017:		
First Quarter	$0.39	$0.59
Second Quarter	$0.37	$0.56

(a) For each quarter, the subordination threshold equals 80% of the target distribution and the incentive threshold equals 120% of the target distribution. The subordination and incentive thresholds terminate after the distribution is made for the fourth full calendar quarter following Chesapeake's completion of its drilling obligation.

(b) A distribution of $0.6454 per common unit was paid on May 30, 2014 to unitholders of record as of May 20, 2014. As the common unit distribution was below the subordination threshold, no distribution was paid for the subordinated units.

(c) A distribution of $0.5796 per common unit was declared on August 7, 2014 to unitholders of record as of August 19, 2014. The distribution will be paid on August 29, 2014. As the common unit distribution is below the subordination threshold, no distribution was declared for the subordinated units.

Results of Trust Operations

The quarterly payments to the Trust with respect to the Royalty Interests are based on the amount of proceeds actually received by Chesapeake during the preceding calendar quarter. Proceeds from production are typically received by Chesapeake one month after production. Due to the timing of the payment of production proceeds, quarterly distributions made by Chesapeake to the Trust generally include royalties attributable to sales of oil, NGL and natural gas for three months, comprised of the first two months of the quarter just ended and the last month of the quarter prior to that one. Chesapeake is required to make the Royalty Interest payments to the Trust within 35 days of the end of each calendar quarter. During the six months ended June 30, 2014, the Trust received payments on the Royalty Interests representing royalties attributable to proceeds from sales of oil, NGL and natural gas for September 1, 2013 through February 28, 2014.

The Trust’s income available for distribution throughout 2013 and 2014 has been adversely affected by several factors. Lower natural gas prices combined with stronger oil prices have resulted in an industry-wide increase in drilling activity in oil- and NGL-rich plays since 2010. The resulting increase in production volumes of NGL led to a significant

decrease in the price of NGL in both absolute terms and on a relative basis compared to oil. In addition to the Trust's exposure to low prices for natural gas and NGL, the Trust experienced reduced production volumes throughout 2013 and 2014, largely due to higher-than-expected pressure depletion within the AMI described below. For the quarterly production periods from September 1, 2013 to November 31, 2013 and December 1, 2013 to February 28, 2014, the Trust paid a common unit distribution below the subordination threshold and no subordinated distribution was paid. Low levels of future production would continue to reduce the Trust’s revenues and distributable income available to unitholders and would likely result in continued distributions to common unitholders at or below the subordination threshold. When a quarterly cash distribution in respect of the common units is lower than the applicable subordination threshold, the common units are not entitled to receive any additional distributions nor are the common units or the subordinated units entitled to arrearages in any future quarter.

During the three months ended June 30, 2014 and March 31, 2014, the Trust recognized approximately $1.0 million and $7.7 million, respectively, in impairments of the Royalty Interests primarily due to lower proved reserve quantities resulting from higher-than-expected pressure depletion within certain areas of the AMI. This depletion has resulted in lower initial production rates and lower expected ultimate recovery in some recent Development Wells. See Investment in Royalty Interests in Note 2 to the financial statements contained in Item 1 of Part I of this Quarterly Report for further discussion of the impairments.

As previously disclosed, Chesapeake reduced its operated rig count in the AMI from four rigs to two rigs in August 2013 to slow the pace of its drilling program and allow more time to apply well performance analysis on a well-to-well basis. Chesapeake is incorporating the results of its analysis of the Colony Granite Wash reservoir into its development plan for the AMI and has made adjustments to well spacing and interval selections in an effort to enhance the value of the remaining Development Wells. The initial indication is that these adjustments will result in less pressure depletion for areas in the AMI where recent Development Wells have been drilled. Chesapeake anticipates that the drilling program will remain at two rigs while it continues to analyze the impact of these adjustments. However, Chesapeake is unable to predict whether these adjustments will continue to result in less pressure depletion in these areas, whether reduced pressure depletion will result in a corresponding improvement in Development Well performance or the effects on future distributions to Trust common unitholders. If well performance does not improve, the Trust's revenues and distributable income available to unitholders will be reduced further, contributing to continued distributions to common unitholders at or below the subordination threshold. Decreased well performance or lower expected ultimate recovery may also lead to further impairments of the Royalty Interests.

Trust Operations for the Three Months Ended June 30, 2014 as compared to June 30, 2013.

Distributable Income. The Trust's distributable income was $22.6 million for the three months ended June 30, 2014 compared to $27.7 million for the three months ended June 30, 2013, a decrease of $5.1 million. This decrease was primarily due to lower-than-expected initial production rates from Development Wells completed in the production period from December 1, 2013 to February 28, 2014 ("current production quarter") as compared to the production period from December 1, 2012 to February 28, 2013 ("prior production quarter"). The decrease was partially offset by an increase in the price received for oil, NGL and natural gas for the current production quarter as compared to the prior production quarter. See Royalty Income below for information regarding the change in average prices received and the change in sales volumes.

On a per unit basis, cash distributions during the three months ended June 30, 2014 and attributable to the current production quarter were $0.6454 per common unit and no subordinated unit distribution was paid as compared to cash distributions of $0.6900 per common unit and $0.3010 per subordinated unit for the three months ended June 30, 2013 and attributable to the prior production quarter. Distributable income for each of the production periods described above was calculated as follows:

	Three Months Ended June 30,	
	2014	2013
	($ in thousands, except per unit data)	
Revenues:		
Royalty income[(a)]	$25,334	$29,868
Expenses:		
Production taxes	486	577
Trust administrative expenses[(b)]	468	573
Derivative settlement loss	1,752	1,007
Total Expenses	2,706	2,157
Distributable income available to unitholders	$22,628	$27,711
Distributable income per common unit (35,062,500 units issued and outstanding)	$0.6454	$0.6900
Distributable income per subordinated unit (11,687,500 units issued and outstanding)[(c)]	$—	$0.3010

(a) Net of certain post-production expenses.
(b) Includes cash reserves withheld.
(c) For the three months ended June 30, 2014, the common unit distribution was below the applicable subordination threshold. As a result, no distribution was declared for the subordinated units.

Royalty Income. Royalty income to the Trust for the three months ended June 30, 2014, and attributable to the current production quarter, totaled $25.3 million based upon sales of production attributable to the Royalty Interests of 102 thousand barrels ("mbbls") of oil, 221 mbbls of NGL and 2,111 million cubic feet ("mmcf") of natural gas. Total production attributable to the Royalty Interests for the current production quarter was 675 thousand barrels of oil equivalent (“mboe”). Average prices received for production, including the impact of certain post-production expenses and excluding production taxes, during the current production quarter were $92.68 per barrel ("bbl") of oil, $40.51 per bbl of NGL and $3.28 per thousand cubic feet ("mcf") of natural gas.

Royalty income to the Trust for the three months ended June 30, 2013, and attributable to the prior production quarter, totaled $29.9 million based upon sales of production attributable to the Royalty Interests of 149 mbbls of oil, 312 mbbls of NGL and 2,886 mmcf of natural gas. Total production attributable to the Royalty Interests for the prior production quarter was 942 mboe. Average prices received for production, including the impact of certain post-production expenses and excluding production taxes, during the prior production quarter were $88.08 per bbl of oil, $32.67 per bbl of NGL and $2.28 per mcf of natural gas.

Production Taxes. Production taxes are calculated as a percentage of oil, NGL and natural gas revenues, net of any applicable tax credits. Production taxes for the three months ended June 30, 2014, and attributable to the current production quarter, totaled $0.5 million, or $0.72 per barrel of oil equivalent (“boe”), as compared to production taxes for the three months ended June 30, 2013, and attributable to the prior production quarter, which totaled $0.6 million, or $0.61 per boe. Production taxes represented approximately 2% of royalty income for each of the three months ended June 30, 2014 and 2013.

Trust Administrative Expenses. Trust administrative expenses, including additional cash reserves, for the three months ended June 30, 2014 totaled $0.5 million as compared to $0.6 million for the three months ended June 30, 2013. Trust administrative expenses primarily consist of the administrative fees paid to the Trustees and Chesapeake and costs for accounting and legal services.

Cash Settlements on Derivatives. The Trust records gains or losses from the derivative contracts when proceeds are received or payments are made, respectively. Swaps covering the current production quarter were settled, during the three months ended June 30, 2014, with proceeds from royalty income for the current production quarter. Total losses during the three months ended June 30, 2014 were $1.8 million. Swaps covering the prior production quarter were settled, during the three months ended June 30, 2013, with proceeds from royalty income for the prior production quarter. Total losses during the three months ended June 30, 2013 were $1.0 million.

Impairments of Royalty Interests. During the three months ended June 30, 2014 and 2013, the Trust recognized approximately $1.0 million and $11.4 million in impairments of the Royalty Interests, respectively. The impairments were the result of downward reserve revisions attributable to production being below expectations, primarily as a result of higher-than-expected pressure depletion within some areas of the AMI. The impairments resulted in a non-cash charge to Trust corpus and did not affect the Trust's distributable income. See Risks and Uncertainties in Note 2 of the notes to our financial statements included in Item I of Part I of this Quarterly Report for further discussion of the impairments.

Trust Operations for the Six Months Ended June 30, 2014 as compared to June 30, 2013.

Distributable Income. The Trust's distributable income was $45.9 million for the six months ended June 30, 2014 compared to $55.6 million for the six months ended June 30, 2013, a decrease of $9.7 million. This decrease was primarily due to lower-than-expected initial production rates from Development Wells completed in the production period from September 1, 2013 to February 28, 2014 ("current production period") as compared to the production period from September 1, 2012 to February 28, 2013 ("prior production period"). The decrease was partially offset by an increase in the price received for oil, NGL and natural gas for the current production period as compared to the prior production period. See Royalty Income below for information regarding the change in average prices received and the change in sales volumes.

On a per unit basis, cash distributions during the six months ended June 30, 2014 and attributable to the current production period were $1.3078 per common unit and no subordinated unit distributions were paid as compared to $1.3600 per common unit and $0.6782 per subordinated unit for the six months ended June 30, 2013 and attributable to the prior production period. Distributable income for the six months ended June 30, 2014, and attributable to the current production period, and the six months ended June 30, 2013, and attributable to prior production period, was calculated as follows:

	Six Months Ended June 30,	
	2014	2013
	($ in thousands, except per unit data)	
Revenues:		
Royalty income[(a)]	$51,656	$59,331
Expenses:		
Production taxes	999	1,165
Trust administrative expenses[(b)]	785	939
Derivative settlement loss	4,017	1,616
Total Expenses	5,801	3,720
Distributable income available to unitholders	$45,855	$55,611
Distributable income per common unit (35,062,500 units issued and outstanding)	$1.3078	$1.3600
Distributable income per subordinated unit (11,687,500 units issued and outstanding)[(c)]	$—	$0.6782

(a) Net of certain post-production expenses.
(b) Includes cash reserves withheld.
(c) For the six months ended June 30, 2014, the common unit distributions were below the applicable subordination thresholds. As a result, no distributions were declared for the subordinated units.

Royalty Income. Royalty income to the Trust for the six months ended June 30, 2014, and attributable to the current production period, totaled $51.7 million based upon sales of production attributable to the Royalty Interests of 217 mbbls of oil, 501 mbbls of NGL and 4,599 mmcf of natural gas. Total production attributable to the Royalty Interests for the current production period was 1,484 mboe. Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production taxes, during the current production period were $94.50 per bbl, $37.23 per bbl and $2.72 per mcf, respectively.

Royalty income to the Trust for the six months ended June 30, 2013, and attributable the prior production period, totaled $59.3 million based upon sales of production attributable to the Royalty Interests of 300 mbbls of oil, 641 mbbls of NGL and 5,946 mmcf of natural gas. Total production attributable to the Royalty Interests for the prior production period was 1,932 mboe. Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production taxes, during the prior production period were $87.16 per bbl, $32.29 per bbl and $2.10 per mcf, respectively.

Production Taxes. Production taxes are calculated as a percentage of oil, NGL and natural gas revenues, net of any applicable tax credits. Production taxes for the six months ended June 30, 2014 and attributable to the current production period totaled $1.0 million, or $0.67 per boe as compared to production taxes for the six months ended June 30, 2013 and attributable to the prior production period, which totaled $1.2 million, or $0.60 per boe. In both periods, production taxes were approximately 2% of royalty income.

Trust Administrative Expenses. Trust administrative expenses, including additional cash reserves, for the six months ended June 30, 2014 totaled $0.8 million as compared to $0.9 million for the six months ended June 30, 2013. Trust administrative expenses primarily consist of the administrative fees paid to the Trustees and Chesapeake and costs for accounting and legal services.

Cash Settlements on Derivatives. The Trust records gains or losses from the derivative contracts when proceeds are received or payments are made, respectively. Swaps covering the current production period were settled, during the six months ended June 30, 2014, with proceeds from royalty income for the current production period. Total losses during the six months ended June 30, 2014 were $4.0 million. Swaps covering the prior production period were settled, during the six months ended June 30, 2013, with proceeds from royalty income for the prior production period. Total losses during the six months ended June 30, 2013 were $1.6 million.

Impairment of Royalty Interests. During the six months ended June 30, 2014 and 2013, the Trust recognized approximately $8.6 million and $44.3 million in impairments of the Royalty Interests, respectively. The impairments were the result of reserve revisions attributable to production being below expectations, primarily as a result of higher-than-expected pressure depletion within certain areas of the AMI. This has resulted in lower initial production rates and lower expected ultimate recovery in certain development wells. The impairments resulted in a non-cash charge to Trust corpus and did not affect the Trust's distributable income. See Risks and Uncertainties in Note 2 of the notes to our financial statements included in Item I of Part I of this Quarterly Report for further discussion of the impairments.

Liquidity and Capital Resources

The Trust’s principal sources of liquidity and capital are cash flows generated from the Royalty Interests, the loan commitment as described below and, during periods in which oil prices fall below the fixed price received on derivative contracts, the derivative contracts. The Trust’s primary uses of cash are distributions to Trust unitholders, including, if applicable, incentive distributions to Chesapeake, payments of production taxes, payments of Trust administrative expenses, including any reserves established by the Trustee for future liabilities and repayment of loans, payments for derivative contract settlements and payments of expense reimbursements to Chesapeake for out-of-pocket expenses it incurs on behalf of the Trust. Administrative expenses include payments to the Trustee and the Delaware Trustee as well as a quarterly fee of $50,000 to Chesapeake pursuant to an administrative services agreement. Each quarter, the Trustee determines the amount of funds available for distribution. Available funds are the excess cash, if any, received by the Trust from the sales of oil, NGL and natural gas production attributable to the Royalty Interests during the quarter, over the Trust’s expenses for the quarter and any cash reserve for the payment of liabilities of the Trust, subject in all cases to the subordination and incentive provisions described previously.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust’s administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. The first quarter distribution of $0.6624 per common unit, consisting of proceeds attributable to production from September 1, 2013 through November 30, 2013 was made on March 3, 2014 to record unitholders as of February 19, 2014. The current quarter distribution of $0.6454 per common unit, consisting of proceeds attributable to production from December 1, 2013 through February 28, 2014, was made on May 30, 2014 to record unitholders as of May 20, 2014.

On August 7, 2014, the Trust declared a cash distribution of $0.5796 per common unit, consisting of proceeds attributable to production from March 1, 2014 to May 31, 2014. The distribution will be paid on August 29, 2014 to record unitholders as of August 19, 2014. The Trust's quarterly income available for distribution was $0.4347 per unit, which was $0.2453 below the applicable subordination threshold of $0.6800. All of the quarterly income available for distribution will be used to make the common unit distribution and no subordinated unit distribution will be paid.

Distributable income attributable to production from March 1, 2014 to May 31, 2014 was calculated as follows (in thousands except for unit and per unit amounts):

REVENUES:	
Royalty income[(a)]	$23,606
EXPENSES:	
Production taxes	494
Trust administrative expenses[(b)]	408
Derivative settlement loss	2,383
Total Expenses	3,285
Distributable income available to unitholders	$20,321
Distributable income per common unit (35,062,500 units)	$0.5796
Distributable income per subordinated unit (11,687,500 units)[(c)]	$—

(a) Net of certain post-production expenses.

(b) Includes cash reserves withheld.

(c) As the common unit distribution is below the applicable subordination threshold, no distribution was declared for the subordinated units.

The Trustee can authorize the Trust to borrow money to pay Trust expenses that exceed cash held by the Trust. The Trustee may authorize the Trust to borrow from the Trustee as a lender provided the terms of the loan are fair to the Trust unitholders. The Trustee may also deposit funds awaiting distribution in an account with itself, if the interest paid to the Trust at least equals amounts paid by the Trustee on similar deposits, and make other short-term investments with the funds distributed to the Trust. The Trustee may also hold funds awaiting distribution in a non-interest bearing account.

Pursuant to the Trust Agreement, if at any time the Trust's cash on hand (including cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will loan funds to the Trust necessary to pay such expenses. Any funds loaned by Chesapeake pursuant to this commitment will be limited to the payment of current accounts payable or other obligations to trade creditors in connection with obtaining goods or services or the payment of other current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans funds pursuant to this commitment, unless Chesapeake agrees otherwise, no further distributions may be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid. There were no loans outstanding as of June 30, 2014 or December 31, 2013.

The Trust is not responsible for any costs related to the drilling of the Development Wells and Chesapeake granted to the Trust the Drilling Support Lien in order to secure the estimated amount of the drilling costs for the Trust's interests in the Development Wells. As Chesapeake fulfills its drilling obligation over time, Development Wells that are completed or that are perforated for completion and then plugged and abandoned are released from the Drilling Support Lien and the total dollar amount that may be recovered by the Trust for Chesapeake's failure to fulfill its drilling obligation is proportionately reduced.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements. The Trust has not guaranteed the debt of any other party, nor does the Trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations other than the derivative contracts disclosed in the section Derivative Contracts in Note 3 in Item 1 of Part I of this Quarterly Report.

Critical Accounting Policies and Estimates

Refer to Note 2 of the notes to our financial statements included in Item 1 of Part I of this Quarterly Report for a discussion of significant accounting policies and estimates that impact the Trust's financial statements. Critical accounting policies and estimates relating to the Trust are contained in Item 7 of the 2013 Form 10-K.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

The discussion in this section provides information about derivative contracts between the Trust and the derivative counterparty effective October 1, 2011. The contracts underlying the derivative contracts cover a portion of the expected production attributable to the Royalty Interests from the Producing Wells and the Development Wells through September 30, 2015. The derivative contracts are settled in cash and do not require the actual delivery of oil or NGL at settlement. The contracts are settled based upon NYMEX prices. Under the derivative contracts, the Trust receives payments directly from the counterparty and pays any amounts owed to the counterparty. The Trust does not have the ability to enter into any additional oil, NGL or natural gas derivative contracts, except in limited circumstances involving the restructuring of the existing oil derivatives contracts.

As of June 30, 2014, the Trust had the following crude oil derivative contracts:

	Fixed-Price Oil Swaps		
Production Quarter	Volume (mbbl)	Weighted Avg. Price (per bbl)	Fair Value Liability ($ in thousands)
Q1 2014[(a)]	59.0	$88.15	$(784)
Q2 2014[(b)]	180.3	$88.21	(2,609)
Q3 2014	178.8	$88.34	(2,834)
Q4 2014	174.3	$88.45	(2,379)
Q1 2015	171.0	$88.59	(1,901)
Q2 2015	175.4	$88.76	(1,485)
Q3 2015	153.6	$88.90	(1,109)
Total	1,092.4	$88.51	$(13,101)

(a) Includes March 2014 production that was settled in August 2014.

(b) Includes April and May 2014 production that was settled in August 2014.

To the extent expected oil production falls below the hedged oil volume, the derivative contracts also cover expected NGL production. Such estimated production of NGL is hedged with crude oil derivative contracts using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. Throughout 2013 and 2014, NGL prices decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the derivative contracts do not effectively mitigate the price risk of the Trust’s NGL production.

The Trust’s obligations to the counterparty under the derivative contracts are secured by liens on proved reserves attributable to the Trust’s interest in the Underlying Properties. The fair value of the derivative contracts as of June 30, 2014 was a net liability of $13.1 million.

Oil, NGL and Natural Gas Price Risk. The Trust’s primary asset and source of income is the Royalty Interests, which generally entitle the Trust to receive a portion of the net proceeds from the sales of oil, NGL and natural gas from the Underlying Properties. The Trust is significantly exposed to fluctuations in the prices received for oil, NGL and natural gas produced and sold. The derivative contracts described above are designed to mitigate a portion of the variability of the prices received for the Trust's share of production. The use of crude oil derivatives to partially mitigate the price risk of NGL production, to the extent oil production falls below the hedged oil volume, is subject to basis risk to the extent oil and NGL prices are not highly correlated.

Credit Risk. A portion of the Trust's liquidity is concentrated in the derivative contracts described above. The use of oil derivative contracts exposes the Trust to credit risk from the counterparty, which has an investment grade credit rating.

Credit Risk Associated with Chesapeake. Chesapeake's ability to perform its obligations to the Trust will depend on its future results of operations, financial condition and liquidity, which in turn will depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

If Chesapeake were to default on its obligation to drill the Development Wells, the Trust would be able to foreclose on the Drilling Support Lien to the extent of Chesapeake's remaining interests in the undeveloped portions of the AMI, file a lawsuit to collect money damages from Chesapeake and pursue other available legal remedies against Chesapeake. However, the Trust is not permitted to obtain specific performance from Chesapeake of its drilling obligation and the maximum amount the Trust can recover in a foreclosure or other action was limited to approximately $54.7 million as of August 4, 2014 and will decease as the remaining Development Wells are drilled and completed.

Delays and expenses associated with a foreclosure could reduce distributions to the Trust unitholders by reducing the amount of proceeds available for distribution and could result in the loss of acreage due to leasehold expirations. Any amounts actually recovered in a foreclosure action would be applied to completion of Chesapeake's drilling obligation, would not result in any distribution to the Trust unitholders and could be insufficient to drill the number of wells needed for the Trust to realize the full value of the Royalty Interests in the Development Wells.

In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed the Royalty Interests to the Trust, the Trust could lose the value of all of the Royalty Interests if a bankruptcy court were to hold that the Royalty Interests constitute an asset of the bankruptcy estate. Chesapeake could also be unable to provide support to the Trust through loans and performance of its management duties.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by Chesapeake to The Bank of New York Mellon Trust Company, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosures. As of the end of the period covered by this Quarterly Report, the Trustee carried out an evaluation of the Trustee's disclosure controls and procedures. Michael J. Ulrich, as Trust Officer of the Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the nature of the Trust as a passive entity and in light of the contractual arrangements pursuant to which the Trust was created, including the provisions of (i) the Trust Agreement, (ii) the administrative services agreement, (iii) the development agreement and (iv) the conveyances granting the Royalty Interests, the Trustee's disclosure controls and procedures related to the Trust necessarily rely on (a) information provided by Chesapeake, including information relating to results of operations, the status of drilling of the Development Wells, the costs and revenues attributable to the Trust's interests under the conveyance and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the underlying properties and the Royalty Interests, and (b) conclusions and reports regarding reserves by the Trust's independent reserve engineers. Other than reviewing the financial and other information provided to the Trust by Chesapeake, the Trustee has not made an independent or direct verification of this financial or other information.

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Changes in Internal Control over Financial Reporting. During the three months ended June 30, 2014, there has been no change in the Trustee's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trustee's internal control over financial reporting related to the Trust. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of Chesapeake.

PART II. OTHER INFORMATION

ITEM 1A. Risk Factors

Risk factors relating to the Trust are contained in Part I, Item 1A of the 2013 Form 10-K. There have not been any material changes from the risk factors previously disclosed in the 2013 Form 10-K.

ITEM 6. Exhibits

The following exhibits are filed or furnished as a part of this report:

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1	Certificate of Trust of Chesapeake Granite Wash Trust.	S-1	333-175395	3.1	7/7/2011		
3.2	Amended and Restated Trust Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake Exploration, L.L.C., The Bank of New York Mellon Trust Company, N.A., as Trustee, Trustee and The Corporation Trust Company, as Delaware Trustee.	8-K	001-35343	3.1	11/21/2011		
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 – Trustee’s Vice President.					X	
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Trustee’s Vice President						X

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: August 7, 2014

CHESAPEAKE GRANITE WASH TRUST

By:	THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A, Trustee
By:	/s/ Michael J. Ulrich
	Michael J. Ulrich
	Vice President

The registrant, Chesapeake Granite Wash Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available, and none have been provided. In signing the report above, the Trustee does not imply that it has performed any such function or that such function exists pursuant to the terms of the Trust Agreement under which it serves.

EXHIBIT INDEX

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32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 – Trustee’s Vice President						X